Entergy New Orleans, LLC
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David D. Ellis
President & CEO

January 18, 2019

Councilmember Helena Moreno
Councilmember-At-Large and
Utilities, Cable, Telecommunications & Technology Committee Chair
1300 Perdido Street, Room 2W40
New Orleans, LA 70112

Re: December 2018 Grand Gulf Nuclear Station Outage

Dear Councilmember Moreno:

This letter is in response to your letter to me of December 19, 2018, inquiring about the unplanned outage that occurred at the Grand Gulf Nuclear Station ("GGNS") on December 12, 2018 (the "Outage"). At the outset, I want to address your initial question regarding why ENO did not notify Councilmembers of the outage. Historically, ENO and the other Entergy Operating Companies have not notified regulators when plant outages occur unless there is reason to believe that the outage will result in a material effect on operations (e.g., the ability to serve load) and/or on customers. Here, there was no reason to believe that the Outage would have such an effect (and, ultimately, it did not, as discussed herein), so ENO did not perceive a need to alter its historic treatment of such events. The fuel and purchased power costs incurred during a plant outage are not included in the fuel adjustment charges on customers' electric bills until the second month after the outage occurs, and it is not possible to estimate that fuel adjustment charge until the month after the outage occurs. With regard to notice, outages to nuclear plants in the U.S. are reported publicly on the NRC's website approximately one day after they begin; however, information related to the potential length of an outage is highly sensitive, non-public information that, if revealed, can have an adverse effect on the energy market prices paid by ENO and, ultimately, its customers. ENO will work with the Advisors and the Council to re-evaluate its historical treatment of plant outage reporting to ensure that it meets the needs of the Council going forward.

Regarding the event itself, a detailed description and technical explanation of the Outage and operational actions taken on December 12^{th} and thereafter is set forth in Attachment 1 to this letter. With regard to your request that we identify the electric generation resources used to serve Entergy New Orleans, LLC's ("ENO's") load while GGNS was in the Outage and the rate impact of using such substitute generation, unfortunately, due to the nature and complexity of the energy markets in which we participate, it is simply not possible to identify the specific generating resources that serve ENO's (or any utility's) load for any given period, whether during an outage or otherwise. We have, however, included below a detailed explanation of why substitute generation cannot be identified with specificity, as well as a preliminary estimate of the MISO revenues that ENO would have received had GGNS been operating, netted against the estimated GGNS fuel costs that ENO avoided due to GGNS being offline. Additionally, we

have provided a preliminary estimate of the February 2019 fuel adjustment clause factor, which would include fuel and purchased power costs incurred while GGNS was in the Outage.

Executive Summary

Each of the issues raised in your letter is addressed in full in Attachment 1 or below, but I have included here a short, high-level summary.

The Outage began on December 12, 2018 and GGNS reconnected to the grid on December 19, 2019, ramping up to full power over the next several days. The high-level cause of the outage was the incorrect operation of a coil in the turbine bypass valve actuator that caused the bypass valve to open when it should not have. There is no known reason the coil should have failed, as it was within its preventive maintenance window. In any event, the turbine bypass system allows steam from the reactor to be routed straight to the condenser without going through the turbine. System operators made the prudent decision to manually shut down the reactor to determine the cause of the bypass valve operation. After analysis of the situation identified the cause of the malfunction, plant personnel wired in a standby coil to be used instead of the failed coil. At no time during the shutdown were reactor pressure or reactor coolant levels in the reactor vessel outside of acceptable parameters. No GGNS plant components were damaged as a result of the shutdown. GGNS resumed operations and re-connected to the grid on December 19, 2018. The Nuclear Regulatory Commission ("NRC") initiated a special investigation as a result of the shutdown and although its Special Inspection Team has completed the on-site work, it is still in the process of finalizing its off-site work. A written report is expected approximately 45 days after that work is complete.

Regarding the effect that the GGNS outage might have on customer costs, I can report that based on preliminary calculations that will be finalized prior to month end, the fuel adjustment charge ("FAC") for February 2019 is expected to be 2.65 cents per kWh, or about 1% less than the January fuel adjustment charge of 2.67 cents per kWh. Additionally, we estimate that ENO would have received approximately $1.7 million in MISO revenues if GGNS had been in operation rather than outage during this period, and that ENO avoided approximately $550,000 in fuel costs, for a net difference of approximately $1.15 million. A more detailed response to these issues follows.

The Difficulty in Identifying Substitute Generation and Corresponding Costs

As noted earlier, ENO is not able to identify which specific electric generation resources are used to meet its demand for electricity (*i.e.,* load) in New Orleans in any given period. As a participant in the MISO market and during the daily operations process, ENO's day-ahead load is bid into the market as a demand bid. At the same time, ENO, as the market participant, offers all of its available generation into the day-ahead market as a resource offer. Using the information in the bids and offers provided by all market participants, MISO runs a security-constrained unit commitment and dispatch model to economically dispatch the full market and optimize the available energy and reserves to ensure that adequate resources are scheduled to be online to meet the market's load for the next day. The goal of this process is to use the least-cost

energy available to meet the required load in aggregate, and thus individual market participant loads are not individually served by specific resources. Real-time operations will differ from the day-ahead resources, with MISO dispatching units in real-time to meet the required load in aggregate rather than specifically for individual market participant loads.

ENO's purchase of wholesale power generated from GGNS under a purchased power agreement, for which ENO is a market participant, is offered into MISO's markets. When GGNS is producing electricity, ENO will receive revenues from MISO that it can use to offset the cost of purchasing its full load requirement and the net of these amounts is recovered through ENO's FAC. When GGNS is not operating, ENO will continue to purchase its full load requirement, but will not receive MISO revenues related to GGNS to offset the costs of the purchase.

We have calculated an estimate in Attachment 2 to this letter that provides a preliminary quantification of these effects for the cost month of December 2019. At a high level, the preliminary estimate reflects the MISO revenues that ENO estimates it would have received had GGNS been operating and nets those revenues against the fuel costs that ENO avoided as a result of GGNS being offline. For the approximately nine days that GGNS was offline in December (December 12 – December 21, 2018), the preliminary estimate indicates a net cost of approximately $1.15 million. The analysis assumes a level of GGNS output based on an average of historical output during certain months of 2018. The estimate uses the average of the actual hourly day-ahead price for wholesale energy in the MISO markets – known as locational marginal prices, or LMPs – during those same days in December (2018) for GGNS. Naturally, the average LMPs reflected in the generation revenue are a function of a variety of factors beyond whether Grand Gulf was generating electricity. Those factors include, for example, the price of natural gas, volumes of customer load and weather impacts, as well as transmission constraints and the availability of other generating units. As noted, this analysis is preliminary and subject to change based on ENO's continued analysis and further refinement, including the availability of actual, as opposed to estimated, data.

Additionally, as noted above, we have prepared a preliminary estimate of the February FAC and based on this calculation, it appears that the February fuel adjustment charge will be 2.65 cents per kWh, or about 1% less than January's fuel adjustment charge, suggesting no material effect on customer rates associated with the Outage.

In addition to the issues addressed above, you have asked that we appear at the January 2019 Utilities, Cable, Telecommunications and Technology Committee meeting to discuss GGNS issues. While we are prepared to do so, if the Council so instructs, we would respectfully suggest that a presentation in February, or even more preferably, March, might provide the Council with better quality information. In particular, we expect that by March we may have the NRC's written report on the Outage. In addition, we will have received a revised settlement statement from MISO for December operations and can provide updated information relating to the unearned MISO revenues associated with the Outage. Please let us know if you have any questions regarding the above or the attached.

In addition to the issues addressed above, you have asked that we appear at the January 2019 Utilities, Cable, Telecommunications and Technology Committee meeting to discuss GGNS issues. While we are prepared to do so, if the Council so instructs, we would respectfully suggest that a presentation in February, or even more preferably, March, might provide the Council with better quality information. In particular, we expect that by March we may have the NRC's written report on the Outage. In addition, we will have received a revised settlement statement from MISO for December operations and can provide updated information relating to the unearned MISO revenues associated with the Outage. Please let us know if you have any questions regarding the above or the attached.

Sincerely,

David D. Ellis
President & CEO

Cc: Council President Jason R. Williams
Councilmember Jay H. Banks
Councilmember Jared C. Brossett
Councilmember Joseph I. Giarrusso
Councilmember Kristin Gisleson Palmer
Councilmember Cyndi Nguyen
Erin Spears, Council Utilities Regulatory Office (via electronic mail)
Clinton A. Vince, Esq.
Philip Movish, P.E.
Roderick K. West

ATTACHMENT 1

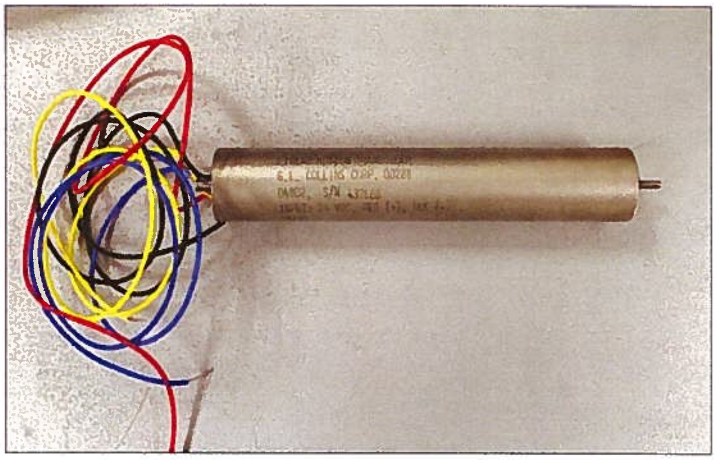
Description of Grand Gulf Outage of December 12, 2018

Around noon on December 12, 2018, Grand Gulf operators detected a partial opening of one of the plant's three turbine bypass valves, specifically valve "A," equipment identification number 1N37F001A. The turbine bypass system allows steam from the reactor to be routed straight to the condenser without going through the turbine. The turbine bypass valves are normally closed during turbine operation, but may be opened to bypass steam whenever steam generated in the reactor is in excess of that required by the turbine. In response to the turbine bypass valve partially opening, operators made a slight reduction in reactor power and continued to monitor the bypass valve while troubleshooting efforts were begun to determine a means to close the valve. Over the course of approximately 90 minutes, the bypass valve moved several times between the closed position and approximately 10% open.

At about 90 minutes after valve opening was first detected, the bypass valve moved to approximately 80% open. As a prudent course of action, plant operators shut down the reactor in order to determine the cause of the bypass valve movement. The reactor was shut down at 1:51 p.m.

Reason for the Outage

Following shutdown, investigation of the bypass valve and its controls identified incorrect operation of a coil in the bypass valve actuator as the cause of the bypass valve being opened. The coil is part of a linear variable differential transformer, or LVDT, whose function is to indicate the position of the bypass valve stem. The LVDT coil was incorrectly reporting the valve stem position to the valve controls, and the controls were attempting to reposition the valve to the correct position based on the incorrect LVDT output. The incorrect signal from the LVDT coil was causing the controls to open and close the valve. Below is a picture of a LVDT coil like the one that provided the incorrect position information:



Each of the plant's three bypass valve assemblies and related controls are removed from service approximately every 120 months (on a staggered basis so that only one valve assembly is removed at a time) and shipped to Siemens AG in Germany for rebuilding and recertification. The bypass valve assembly that incorrectly opened on December 12, 2018 had been rebuilt and recertified by Siemens in 2016. Operation of the bypass valve in the period between its reinstallation in 2016 and to December 12 had been flawless.

An LVDT consists of a coil with primary and secondary windings, through which a magnetically permeable core travels. The core is mechanically connected to the valve stem such that valve stem movement moves the core inside the coil. The primary windings in the coil are energized during operation, and the magnetic field created by the core is sensed in the secondary windings. The position of the core in the coil determines the amount of electrical current that is induced in the secondary windings, and the electrical output from the secondary windings is measured and used to determine where the core is in the coil, and by proxy, where the attached valve stem is positioned.

The LVDT coil is a completely passive component that is not subjected to wear while in service. The coil responds to axial movement of the core and is relatively insensitive to any cross-axial movement, such that even misalignment of the core should not affect the LVDT output. Because LVDTs are not subject to wear and have outstanding reliability, their incorrect operation is not something that would be reasonably expected.

Corrective Actions

After identifying the problem LVDT, plant personnel wired in an already-installed, standby LVDT to provide bypass valve position indication. Testing was conducted on the subject valve, as well as the other two non-affected bypass valves, to ensure proper operation. As a precautionary measure, related control boards were also replaced. Plant instrumentation and controls personnel determined that removal of the failed LVDT coil was a complicated task that could prolong the outage, and that removal was not necessary because of the use of the standby LVDT coil. Accordingly, the failed coil was left *in situ*. The original equipment manufacturer, Siemens, was consulted about this course of action, and recommended that the failed LVDT coil did not need to be removed, and that the robustness of the LVDT design was such that failure of the standby

LVDT coil was highly unlikely. The plant was restarted and synchronized to the grid on December 19, 2018 at 11:46 AM.

Grand Gulf has commenced a project to replace its original-equipment turbine control system to improve plant reliability. This multi-year project is scheduled for completion during refueling outage 22 in 2020. This project will replace the bypass valves and their controls with completely new equipment.

Actions Taken by Operators for Shutdown

As previously noted, plant operators decided to initiate a manual plant shutdown based on the bypass valve's improper operation. Because the steam flow from the reactor could not necessarily be controlled with the bypass valve inoperable, as per plant procedures, plant operators closed the plant's 8 main steam isolation valves (2 in each of 4 main steam lines). Steam was relieved from the reactor through the safety relief valves that discharge into the plant's suppression pool in the containment building, as designed. Operators initiated backfilling of the reactor vessel with water by use of the Reactor Core Isolation Cooling ("RCIC") system and the High Pressure Core Spray ("HPCS") system. Although it was not required for vessel level control or cooling at the time, the primary Control Rod Drive ("CRD") system pump was injecting water into the reactor as well. This is a very low volume system (approximately 100 GPM) that is not needed for reactor safety in this situation. The CRD system pump unexpectedly tripped off when it was initiated, although operators started the standby CRD system pump within one minute of the trip. However, it was not necessary to use the CRD pump for the shutdown.

At no time during the shutdown were reactor pressure or reactor coolant levels in the reactor vessel outside of acceptable parameters. The systems used for backfilling the reactor vessel with reactor coolant were successfully used as designed to maintain correct pressure and level throughout the reactor cooldown sequence.

No Damage to Grand Gulf Systems or Equipment from Outage

No Grand Gulf plant components were damaged as a result of the shutdown.

NRC Response

Pursuant to NRC regulations at 10 CFR §50.72(b), Grand Gulf notified the NRC of the shutdown. The description of the event provided by Grand Gulf was published by the NRC as event report 53788. The NRC was initially concerned about the sequence of events during the shutdown, in particular, the trip of the CRD pump, and sent a Special Inspection Team ("SIT") to look into the outage. As noted above, plant systems were successfully used to maintain reactor conditions during the shutdown, and the CRD pump trip, while unexpected, was inconsequential to the shutdown. The SIT concluded its on-site investigation and is in the process of finalizing its off-site work. A written report is expected within approximately 45 days of the completion of that work. No date has been set for that conclusion.

GG Outage Cost Analysis -- December 2018
Attachment 2

12/12/18-12/21/18	
Avg DA LMP Price at Grand Gulf	$ 0.03222
Average Grand Gulf fuel cost / kWh	0.01040
ENO Average kWh purchased from SERI (UPSA)	46,283,342
ENO Average kWh purchased from EAI (MSS-4)	6,627,370
Total ENO estimated kWHs purchased	52,910,712
Estimated fuel cost not incurred	
ENO	$ (550,271)
Est. generation revenue not received (actual LMP)	
ENO	$ 1,704,903
Net Difference (INC/(DEC) to Expense)	
ENO	$ 1,154,631